Before The State of Wisconsin
Department of Natural Resources

UTILITIES' RESPONSE TO CITIZENS' PETITION:

"PETITION BY CITIZENS FOR THE REVISION AND ADOPTION OF RULES TO GOVERN THE RELEASE OF MERCURY EMISSIONS TO THE AIR (NR 446) FROM COAL-FIRED ELECTRIC GENERATORS AND REQUIRING REDUCTIONS OF THOSE EMISSIONS TO MINIMIZE MERCURY DEPOSITION TO WISCONSIN LAKES AND RIVERS"

TO: The Secretary of the Department of Natural Resources; and
The Natural Resources Board
P.O. Box 7921
Madison, Wisconsin 53707

FROM: Dairyland Power Cooperative, La Crosse
Madison Gas and Electric Company, Madison
We Energies, Milwaukee
Wisconsin Power and Light Company, Madison
Wisconsin Public Service Corporation, Green Bay
Xcel Energy, Eau Claire

I. INTRODUCTION

On January 22, 2007, various environmental and fishing groups (Petitioners) petitioned the Wisconsin Department of Natural Resources (DNR) and Natural Resources Board (NRB or the Board) for rulemaking proceedings to revise and adopt rules addressing mercury emissions to the air from coal-fired electric utility boilers. Petitioners ask DNR to adopt rules that require a 90% or greater reduction in mercury emissions by January 1, 2012 from all coal and oil burning electric utility steam generating units in Wisconsin in order to minimize mercury deposition to Wisconsin lakes and rivers.

The rules requested by Petitioners would be more stringent than the federal Clean Air Mercury Rule (CAMR) which requires these same utilities to achieve a nearly 70% reduction in mercury emissions in two phases -- 36% by 2010 and 69% by 2018. Such rules would also run counter to the United States Environmental Protection Agency (EPA) determination that mercury reductions are most effectively attained by integrating the requirements of CAMR with those of the Clean Air Interstate Rule (CAIR).

As the Board is well aware, Wisconsin is in the midst of implementing an unprecedented number of federal air quality regulations that apply to the state's electricity generating system. It is essential that Wisconsin utilities be allowed to implement an integrated set of emission controls to accomplish reductions in the most cost effective manner possible.

Petitioners' request for more aggressive reductions at an earlier date is not technically feasible and would result in actions that are less cost-effective and have adverse cost consequences to utility customers. Most importantly, the path Petitioners recommend will not accomplish their stated goal to minimize mercury deposition to Wisconsin lakes and rivers.

The information provided in this Response supports the following conclusions:

- Mercury-specific control technologies suited to the Wisconsin coal-fired fleet are not commercially available.
    - Mercury-specific control technologies that could be used by coal-fired power plants in Wisconsin are still in the development and testing stage.
    - Tests have not been conducted on plants with equipment similar to that used by the Wisconsin fleet. What tests have been conducted have been of short duration (days to weeks) and comprehensive vendor guarantees for control performance and/or balance of plant impacts cannot yet be obtained.

- Mercury-specific control technologies are not compatible with the Wisconsin fleet and are not likely to achieve 90% reductions in mercury emissions.
    - Wisconsin utilities use sub-bituminous coal to obtain the significant environmental benefits of lower sulfur dioxide (SO_2) emissions. The properties of the sub-bituminous coals present substantial challenges to capturing mercury emissions.
    - Sorbent injection is a developing technology that contaminates fly ash and makes it unusable in concrete. The environmental loss would be significant -- beneficial use of utility fly ash in concrete reduces energy use, reduces landfill disposal needs, and annually offsets over 500,000 tons of carbon dioxide (CO_2) in Wisconsin.

- There is no compelling benefit to Wisconsin's environment to justify large investments in experimental equipment by Wisconsin ratepayers before the mercury "co-benefits" capability of emission controls required by CAIR are thoroughly evaluated and optimized.

- According to a recent cost study prepared by the Center for Energy and Economic Development (CEED), implementation of the mercury rule proposed by DNR would cost Wisconsin utilities and ratepayers an additional $450 million, more than twice the estimated cost of implementing CAMR according to the federal rule provisions. The rule requested by Petitioners exceeds the stringency of the rule proposed by DNR and would cost substantially more, if it is even technically feasible to achieve.

- Our neighboring states recognize that "one size does not fit all" when designing realistic approaches to mercury emission reduction. Each of these states takes into account the nature of its electricity generating fleet, fuel type, existing emission controls, and the timing and costs of further reductions. The applicability and the specific provisions of their approaches are subject to significant caveats.

- Based on agency and peer-reviewed science, the rules Petitioners request will not achieve the stated goal of minimizing mercury deposition to Wisconsin lakes and rivers.

The facts and science demonstrate this is a complex issue. It is incumbent on the Board to consider this more complicated reality in determining the most appropriate response to the Petitioners' request.

II. PURPOSE OF THIS RESPONSE

To provide the NRB with additional perspective on mercury emission reductions being required of Wisconsin utilities in order to inform a more complete discussion of the appropriate course of action for Wisconsin, this Response:

- *Presents information about the Wisconsin electricity generating fleet.*
    - Coal accounts for over 75% of the energy used by in-state utilities to generate electricity.
    - Wisconsin's existing coal-fired plants primarily (~ 90%) combust sub-bituminous coals that are mined in the western U.S.
    - Sub-bituminous coal provides significant environmental benefits because its lower sulfur content results in lower SO_2 emissions, and its combustion results in significantly less ash byproduct.
    - However, the properties of the sub-bituminous coals, combined with emission control equipment in place or planned for Wisconsin's coal-fired power plants, present very substantial challenges to meeting federal and state mandates for capturing mercury emissions.

- *Discusses the interaction of the applicable federal air quality regulations and the anticipated emission reductions they will achieve in Wisconsin.*
    - In designing CAMR, EPA considered a variety of approaches and ultimately determined the most effective approach overall was to integrate CAIR and CAMR to maximize their environmental benefits and coordinate the investments utilities will make in achieving compliance with both regulations.
    - CAMR Phase I represents the mercury reductions that will be achieved coincident with the new controls required by CAIR to reduce emissions of SO_2 and nitrogen oxides (NOx). CAMR Phase II is to be achieved through the installation of mercury-specific control technologies, which EPA assumes will be ready for large-scale deployment by the Phase II deadline of 2018.
    - Unlike utilities in many eastern states, to achieve greater mercury reductions in 2010 beyond what is required in CAMR Phase I, Wisconsin utilities must either: 1) find ways to modify SO_2 and NO_x equipment to better capture mercury released from burning sub-bituminous coals or 2) invest now in mercury-specific controls that are unproven and would result in significant, and potentially unnecessary, cost impacts.

- *Discusses the status of mercury control technologies, their applicability and costs to Wisconsin's coal-fired power plants.*
    - Mercury-specific control technologies suited to the Wisconsin fleet are not commercially available.
    - The tests that have been conducted have not been done on plants that burn coals or have equipment similar to that used by the Wisconsin fleet.
    - The tests, with but one exception, have been of short duration (days to weeks), and comprehensive vendor guarantees for control performance and/or balance of plant impacts cannot yet be obtained.
    - Sorbent injection will undo a significant environmental victory – the ability to beneficially use fly ash in Wisconsin -- and may lead to greater use of landfills for fly ash disposal. The possible TOXECON solution to the fly ash problem is still under development.
    - The non-mercury-specific technologies (e.g., SO_2 wet scrubbers) will not capture significant amounts of mercury at plants in Wisconsin.

- *Provides more information about the status of mercury regulations in neighboring states, including the applicability of those regulations to power plants located in those states and the relevant state-specific circumstances associated with those regulations.*
    - In Illinois, less than 50% of the state's electricity is generated from coal-fired units. Illinois' rule largely reflects the outcome of negotiated multi-emissions agreements reached with the state's largest utilities and includes other temporary rule exceptions, including emission averaging provisions, and a "temporary technology control option" that recognizes the uncertainty of mercury control technology performance.
    - In Minnesota, the 90% reduction requirement applies to just six units at three facilities (owned by two utilities), most of which are already fitted with control equipment, making the 90% requirement much less costly to implement. A provision allowing supplemental units reduces the effective reduction level for one of the two affected utilities to 70%. Minnesota has not determined how it will implement CAMR for the 21 remaining coal-fired units in the state.
    - In Michigan, proposed rules have been under development since the Governor's announcement in April 2006 and are not yet final. The Governor has directed that the rules include both a technical and a cost-based rule exception. Neither of these has been drafted yet.

- *Provides a summary of the science which supports EPA's assessment that minimal changes in mercury loadings to Wisconsin's environment would likely result from more aggressive mercury regulations in Wisconsin.*
    - Based on agency and peer-reviewed science, the rules Petitioners request will not achieve the stated goal of minimizing mercury deposition to Wisconsin lakes and rivers.

III. WISCONSIN'S ELECTRICITY GENERATING FLEET

A. Wisconsin's Electricity Generating Fleet: Fuel Type

Coal-fired power plants in Wisconsin provide the majority of electricity consumed by the state's residential, commercial and industrial customers. Wisconsin's utilities rely on coal to generate electricity, to maintain fuel diversity, and to retain affordable rates for consumers. According to the Wisconsin Division of Energy, coal accounted for over 75% of the energy used by in-state utilities to generate electricity in 2005[1]. (Figure 1)

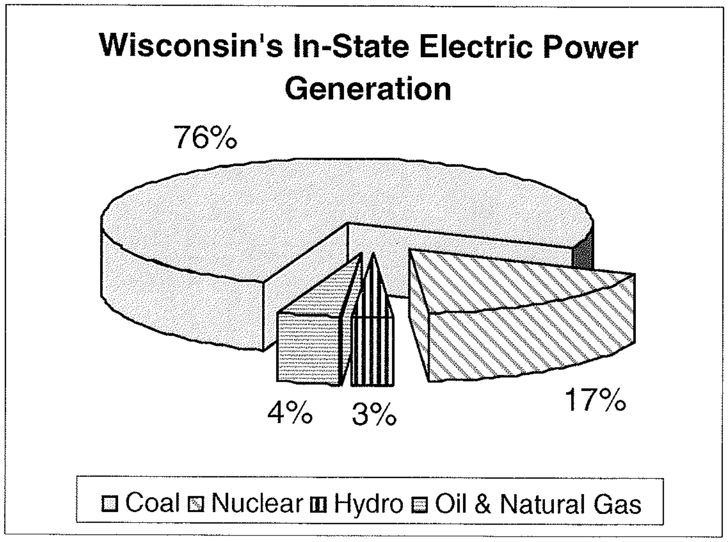

Figure 1. Fuel used in Wisconsin to generate electric power.

B. Wisconsin's Coal-fired Electricity Generating Fleet: Coal Type

Wisconsin's existing coal-fired plants primarily (~ 90%) burn sub-bituminous coals that are mined in the western U.S. The balance of coal burned is bituminous. The good news is that sub-bituminous coal provides significant environmental benefits because its lower sulfur content results in lower SO_2 emissions, and its combustion results in significantly less ash byproduct. Because sub-bituminous coal is less expensive than bituminous coal, these environmental benefits are delivered at lower cost to the ratepayers.

However, the bad news is that the properties of the sub-bituminous coals, in concert with emission control equipment in place or planned for the State's coal-fired power plants, present very substantial challenges to meeting federal and state mandates for capturing mercury emissions.

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[1] The data regarding coal use in Wisconsin is from the Wisconsin Division of Energy's Wisconsin Energy Statistics Report (2006), which is available at http://www.doa.state.wi.us/pagesubtext_detail.asp?linksubcatid=601&linkcatid=109&linkid= .

The challenge presented by the properties of sub-bituminous coals is due to the chemical form of mercury that is released following combustion in the boiler. Extensive measurements by the Electric Power Research Institute (EPRI) and Department of Energy–National Energy Technology Laboratory (DOE-NETL) at power plants, including some in Wisconsin, have clearly shown that sub-bituminous coal-fired power plants do not emit large quantities of oxidized, or water soluble mercury – the form of mercury most easily captured by other types of controls, e.g. SO_2 controls. Only 10-30% of the mercury emitted by Wisconsin's plants is the oxidized form. This is important for reasons discussed later in this Response. Briefly, the chemical form of mercury present in utility boiler flue gas:

- bears significantly on the efficacy of certain existing non-mercury-specific and promising new mercury-specific control technologies to capture mercury; and
- has significant ramifications on the ultimate environmental fate of the mercury following release should it not be captured by control equipment.

C. Wisconsin's Coal-fired Power Plants: SO_2 Controls

To comply with state and federal acid rain requirements, in the 1980s Wisconsin utilities adopted a strategy of fuel switching from bituminous coals to low sulfur sub-bituminous coals to reduce SO_2 emissions because it is the most cost-effective means of compliance. In other parts of the country, some plants chose instead to install Flue Gas Desulfurization (FGD) controls as add-on technology to remove SO_2 emissions. Since Wisconsin utilities had access to low sulfur coal at competitive prices, the most cost-effective way to reduce SO_2 emissions was to switch coals instead of continuing to burn higher sulfur coals and installing add-on SO_2 emission controls.

There are two types of FGD systems, wet and dry systems, and they are typically referred to as "scrubbers". The basic difference between wet and dry scrubbers involves the method by which lime or limestone powder is allowed to react with the gas stream containing SO_2.

- In wet systems, the powder is mixed with water and this mixture is sprayed into the gas stream within a large reaction chamber. The reaction produces calcium sulfate (gypsum), which is a marketable byproduct.
- In dry systems, the powder is sprayed into a chamber called an absorber where it reacts directly with SO_2. The reacted mixture is then collected by a particulate control device, usually a fabric filter. The reacted mixture currently has no commercial value since it usually contains high amounts of fly ash as well as calcium reaction products. Dry systems are used most often in water-constrained areas of the U.S.

Currently, one plant in Wisconsin has installed wet scrubbers, and another has contracted and is currently in the design phase for adding a dry scrubber[2], to further control SO_2 emissions in anticipation of the CAIR SO_2 reduction requirements. However, as limits on SO_2 emissions are lowered, utilities will be moving towards installing additional SO_2 control equipment.

[2] We Energies Pleasant Prairie Power Plant has installed wet scrubbers that began operation in 2006-07, and dry scrubbers are being designed for Dairyland's Genoa Unit 3 to begin operation in 2009.

D. Wisconsin's Coal-fired Power Plants: Particulate Controls

Wisconsin's coal-fired power plants employ two technologies to control particulate emissions: electrostatic precipitators and fabric filters. In both cases, particulate matter in the form of fly ash is collected from the flue gas.

1. Electrostatic Precipitators (ESPs)

Wisconsin's coal-fired power plants primarily employ electrostatic precipitators (ESPs) to control particulate emissions. The ESP is also the primary technology used by power plants throughout the United States to control particulate emissions.

Two key features of existing ESPs have important ramifications for control of mercury emissions: operating temperature and collection plate size. A "hot-side ESP" typically operates at temperatures above 600 degrees, while a "cold-side ESP" operates at much cooler temperatures, often around 300 degrees. It is much more difficult to control mercury emissions if the plant is equipped with a hot-side ESP due to the inability of fly ash and unburned carbon particles present in the very hot flue gas to absorb mercury vapors. Approximately 15 percent of the coal-fired generating capacity in Wisconsin uses hot-side ESPs.

In general, ESPs are able to remove 99 percent or more of particulate matter emissions from the flue gas. To do so, ESPs are designed with sufficient collection plate area to capture the predicted amount of particulate matter (ash) present in the flue gas. Existing ESPs typically do not have excess collection plate area to accommodate particulate loadings in excess of the design conditions. Thus, they do not have the collection plate area necessary to capture the additional particulate matter, in the form of an injected sorbent material from the retrofit of sorbent-based control equipment, that will reduce mercury emissions. As Figure 2 demonstrates, many plants in the U.S., including most of the smaller units in Wisconsin, have ESPs that do not have excess collection plate area. This problem is discussed later in this Response with respect to mercury-specific controls such as sorbent injection.

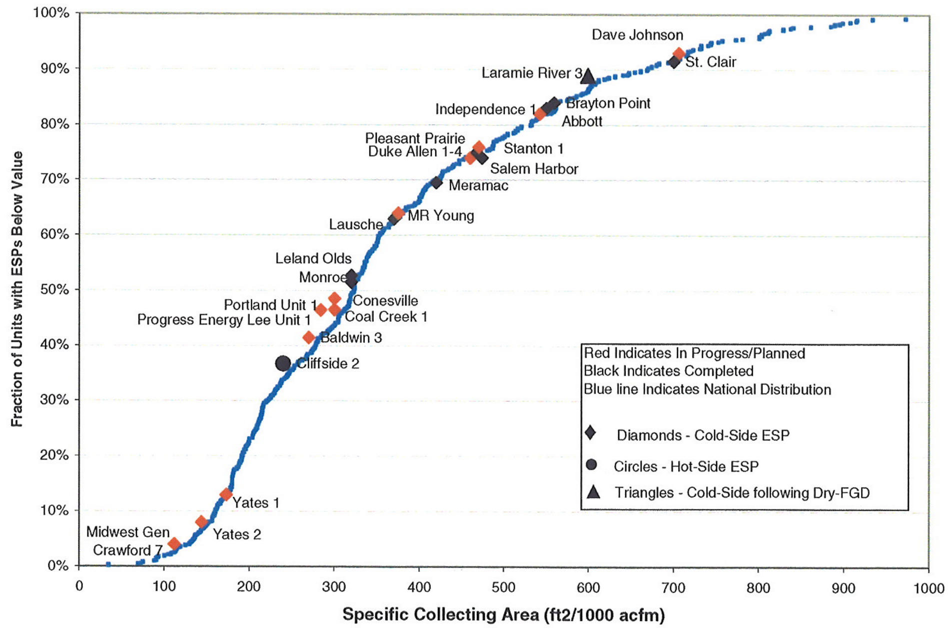

Figure 2. A distribution of ESP-specific collection plate area values for the nation's ESP-equipped power plants. The symbols on the figure illustrate those plants that have been tested with sorbent injection for mercury control. Most of the sorbent injection tests have been done at plants with larger than average (~300 Specific Collection Area ft^2/ 1000 actual cubic feet per minute [acfm]) ESPs.

2. Fabric Filters (Baghouses)

The other type of particulate emission control technology is the fabric filter, or baghouse. This is a more recently developed technology for the electricity generating industry. It is used for greater fuel flexibility and when needed as a secondary particulate control device.

The fabric filter is a structure containing thousands of filter bags, where the fly ash is collected on the fabric of the bag. This is similar in concept to a shop vacuum or "shop vac." Only four plants (five units) in Wisconsin[3] currently employ a fabric filter particulate emission control system. Two of the four plants are in the process of initial fabric filter start-up testing as of this writing. A fabric filter is a significant investment, on the order of $100-150 / kW for small, add-on installations downstream of existing ESPs. For existing 300 MW plants, this would translate into capital costs of $30-45 million/unit.

3. The beneficial use of fly ash

As noted, both ESPs and fabric filters capture fly ash, which is typically sold to the concrete industry. Fly ash that is used in concrete not only saves money for large public and private

[3] Dairyland Power Cooperative Genoa Unit 1 and Madgett Unit 1; We Energies Valley Power Plant, Units 1 and 2; and Wisconsin Public Service Corporation Weston Unit 3 .

construction projects requiring concrete, but also saves energy and natural resources. The use of fly ash in concrete offsets the production of portland cement powder which is a very energy-intensive process that emits approximately one ton of CO_2 for every ton of cement produced[4]. Therefore it can be estimated from the American Coal Ash Association *2005 Coal Combustion Product Production and Use Survey* that fly ash use in concrete annually offsets over 15,000,000 tons of CO_2 in the US and 500,000 tons of CO_2 in Wisconsin.

Many utilities in the state sell their high quality fly ash and these revenues help to lower Wisconsin electricity rates[5]. Fly ash must meet numerous quality standards in order for it to be used in most construction applications. Carbon-based sorbent injection interferes with the ability to embed air bubbles in the concrete that allow it to expand and contract without cracking when the ambient temperature changes. Any residual mercury itself is not an issue as it is immobilized in the concrete.

Coal ash utilization has the additional environmental benefit of reducing the need to expand existing landfills and develop new ash landfills which are necessary for the disposal of fly ash that is not recycled. According to WDNR *Beneficial Use of Industrial Byproducts 2000 Usage Summary*, Wisconsin beneficially utilized 1.31 million tons of coal ash in 2000. Using EPA's conversion factor (656 acre-feet for every one million tons of coal ash), this translates to avoiding 860 acre-feet of landfill space in the year 2000, and this volume is likely to be significantly higher in the year 2007. For more information on ash utilization, refer to the following website links:

www.acaa-org.org
www.epa.gov/epaoswer/osw/conserve/c2p2/

E. Summary

In summary, Wisconsin utility coal-fired power plants primarily burn sub-bituminous coal. Sub-bituminous coal primarily yields a non-water soluble form of mercury called elemental mercury. The existing plants, with one exception, are not currently equipped with wet or dry scrubbers for SO_2 control. The existing plants are primarily equipped with ESPs for particulate control. All of these factors negatively impact the ability of existing plants to capture mercury. These factors also impact the ability of developing mercury-specific control technologies to capture 90% of the mercury released by burning sub-bituminous coals as discussed later in this Response.

IV. CAIR AND CAMR

Any complete discussion of mercury emission reductions from coal-fired boilers must take into account the impact both CAIR and CAMR will have on the state's coal-fired power plants. CAIR is designed to control SO_2 and NO_x emissions from electric utilities. CAMR is designed

[4] United States E.P.A., *Using Coal Ash in Highway Construction: A Guide to Benefits and Impacts* (EPA-530-K-05-002, April 2005).
[5] Dairyland Power beneficially uses 73% of its fly ash; Madison Gas & Electric beneficially uses 100% of its fly ash; We Energies beneficially uses 100% of its fly ash; Wisconsin Power & Light beneficially uses 82% of its fly ash; Wisconsin Public Service Corporation beneficially uses 99% of its Wisconsin fly ash; Xcel Energy beneficially uses 100% of its fly ash from its Bay Front Plant.

to control mercury emissions from electric utilities. In designing CAMR, EPA considered a variety of approaches and ultimately determined the most effective approach overall is to integrate CAIR and CAMR to maximize the environmental benefits and coordinate the investments (the new controls being placed on power plants for removal of SO_2 and NOx) utilities will make in achieving compliance with both regulations.

To do that, EPA structured CAMR to require nation-wide reductions from the utility coal-fired boiler sector to occur in two phases:

1. CAMR **Phase I** requires a 36% reduction from 2001 emission levels (i.e., from 48 tons /yr to 38 tons / yr). Phase I represents the mercury reductions that will be achieved coincident with the new controls required by CAIR to reduce emissions of SO_2 and NOx.
    - These reductions in mercury emissions are referred to as "co-benefits" of reducing emissions of SO_2 and NO_x in that the mercury reductions to be achieved are "coincidental" to the reductions in SO_2 and NO_x emissions achieved by SO_2 and NO_x control equipment.
    - EPA is expecting that CAMR Phase I mercury reductions will largely occur via the use of **non-mercury-specific** control technologies to be installed and operating by the Phase I deadline of 2010.

2. CAMR **Phase II** requires a 69% reduction from 2001 emission levels (i.e., from 48 tons/yr to 15 tons/yr).
    - Phase II is to be achieved through the installation of **mercury-specific** control technologies.
    - It is based on the assumption that such mercury-specific control technologies will be ready for large-scale deployment by the Phase II deadline of 2018.

Research has demonstrated that power plants burning **eastern bituminous** coal and subject to the CAIR provisions, which utilize wet Flue Gas Desulfurization (wFGD) and Selective Catalytic Reduction (SCR) controls for SO_2 and NOx, will substantially capture mercury as well as SO_2 and NOx. For the most part, mercury reductions for this suite of air emission controls on this coal type have ranged between 70% and 90% in demonstration testing done to date.

However, for plants that are subject to CAIR and burn **sub-bituminous** coal – the predominant situation with the Wisconsin fleet -- the installation of wFGD and SCR technology provides little additional mercury capture, perhaps on the order of 20-30%. This is because burning sub-bituminous coal releases only small amounts of water soluble, oxidized mercury and wet scrubbers only capture the **water soluble** form of mercury present in the flue gas.

Therefore, unlike utilities in many eastern states, to achieve mercury reductions by 2010 beyond what is required in Phase I of CAMR, Wisconsin utilities must either: 1) find ways to modify SO_2 and NO_x equipment to better capture mercury released from burning sub-bituminous coals or 2) invest now in mercury-specific controls that are unproven and would result in significant, and potentially unnecessary, cost impacts.

Research is underway to enhance the mercury capture performance of these SO_2 and NO_x control technologies when installed on units burning sub-bituminous coals. Several strategies are being explored. Most involve techniques to convert elemental mercury present in flue gas into oxidized mercury that can then be captured with wFGD systems. Other strategies involve adding chemicals to the coal being burned to cause changes in the form of mercury that is present in the flue gas. For units that install SCRs, the goal is to develop catalysts that function as NOx controls as well as oxidizers of elemental mercury. Few full-scale tests have been performed to date and the possible impacts on power plant equipment have not yet been determined. All of these potential solutions are very experimental and are not nearing commercial readiness at this time.

While it is possible that there may be a need to accelerate installation of some amount of mercury-specific controls on Wisconsin power plants in order to meet Phase I of CAMR, this is not the most preferred technology solution, nor the most prudent economic approach for meeting the federal requirements. This is because mercury-specific control equipment is only in the initial phases of testing. As such, purchase of these developing technologies at this time poses significant economic and compliance risk to utilities, risks that were acknowledged by EPA and DOE-NETL in 2005[6]. This problem would be significantly exacerbated if Wisconsin's utilities would have to achieve a 90% reduction in emissions by 2012, as proposed by Petitioners. Importantly, as discussed in Section VI, there is no compelling benefit to Wisconsin's environment to justify large investments in experimental equipment by Wisconsin ratepayers before the mercury "co-benefits" capability of emission controls required by CAIR are thoroughly evaluated and optimized.

V. MERCURY-SPECIFIC CONTROL TECHNOLOGIES AND THEIR APPLICABILITY TO WISCONSIN'S COAL-FIRED POWER PLANTS

The ultimate question raised by the Petition is this: should DNR adopt a rule in 2007 that requires Wisconsin's coal-fired utilities to reduce mercury emissions by 90% by 2012?

To answer that question, it is reasonable to ask and answer these questions first:

- Are mercury-specific control technologies considered to be "commercially available"?
  No.
- Are mercury-specific control technologies compatible with the Wisconsin fleet and will they likely achieve 90% reductions?
  No.
- What will wide-scale application of these technologies cost?

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[6] EPA: http://www.epa.gov/ttn/atw/utility/ord_whtpaper_hgcontroltech_oar-2002-0056-6141.pdf and DOE-NETL: http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/mercuryR%26D-v4-0505.pdf

At least twice as much ($450 million more) as the estimated cost to comply with CAMR.

- Is it technically feasible to install these technologies by 2012?
  No.
- If installed, will they achieve Petitioners' goal of meaningful reductions in mercury deposition to Wisconsin lakes and rivers?
  No.

A. Mercury-specific control technologies suited to the Wisconsin fleet are not commercially available.

1. Mercury-specific control technology that could be used by coal-fired power plants in Wisconsin is still in the development and testing stage.

There is very limited information available yet about how new mercury-specific controls impact actual power plant operations. New technology is deemed "commercially available" only after it has been proven to be compatible with overall plant operations. Power industry engineers determine whether new technology is compatible with plant operations based on the technology's "balance of plant" impacts. Balance of plant impacts describe how a piece of equipment might impact the operation of the entire plant or the operation of other critical emission control equipment, such as ESPs, baghouses, or SO_2 scrubbers. Short-term tests of new technologies over a period of days or weeks are insufficient to fully identify balance of plant impacts. This is particularity true for the electricity generating industry where there is a very high standard for operational reliability. The regulatory requirement for continuous compliance with permit conditions for other emission limitations is also an important factor. All reasonable operational uncertainties about the impacts of the new equipment on other emission control systems must be resolved before the new equipment can be deemed commercially available.

Also of great importance for new emission control technologies is the issue of vendor guarantees or warrantees. Many vendors limit the liability of their performance guarantee for the new emission control equipment. Vendors often limit the value of their performance guarantee to the value of the contract for the *capital* equipment supplied. This is problematic for emission control equipment since total cost can be dominated by operational and maintenance costs versus capital equipment costs. The practical impact of this type of performance guarantee is that the owner ends up bearing a portion of the financial responsibility for the lower technology performance - through increased O&M costs over the life of the equipment once the performance guarantee amounting to the capital cost of the equipment runs out. With mercury controls, when the total cost of the equipment is dominated by operational versus capital costs, this impact could be substantial.

While sorbent injection vendors may offer guarantees for their own equipment, no vendor has taken the next step to cover damages to other power plant equipment. This includes impacts on other emission control equipment caused by the sorbent injection. Vendor guarantees do not yet cover the costs associated with generation losses that may be experienced by a utility if the sorbent injection equipment were to either fail to meet permit reduction requirements or damage other plant equipment. In either case, this unit would have to be removed from service. The costs associated with equipment failures or lost generation due to an unscheduled plant outage would ultimately be borne by the ratepayers.

2. Available test data on mercury-specific technologies is valuable but still limited.

Petitioners list 41 sites where mercury capture testing involving the most promising mercury-specific control technology, i.e., sorbent injection, has occurred since 2001. (Petition, Table at pp. 7-8). Petitioners point to these "full-scale" tests and vendor sales of sorbent injection systems as proof that mercury-specific control technology has been widely tested; that these test results are conclusive as to the technology's performance and reliability; and, thus, the technology is "commercially available". For the reasons explained below, we disagree with this conclusion.

While quite valuable in terms of the insights they provide, these tests are too limited in design and duration to justify a conclusion that this technology is commercially available[7]. Petitioners' Table lists power plants that have been tested with sorbent injection technology. This data is of limited value for assessing this technology's performance at Wisconsin's existing coal-fired plants because:

- Many of the tested plants: are fueled by coals that are not used by Wisconsin's utilities; have been equipped with a variety of air emission controls for SO_2 and NOx, as well as particulate matter, that are not in place at plants located in Wisconsin; have been tested using prototype sorbent injection systems.
- The tests, with but one exception, were of relatively short duration (days to weeks).

In addition, characterization of these sorbent injection tests as "full-scale" is not accurate. For example:

- At one of the most thoroughly studied plants, Alabama Power's Plant Gaston, which burns low sulfur eastern bituminous coal, one-half of one small fabric filter unit was tested - not the entire fabric filter and not the entire plant.
- At Detroit Edison's St. Claire River Plant, one-half of one ESP for one of six units was tested for periods up to 30 days.
- At We Energies' Pleasant Prairie Power Plant, one-fourth of one ESP was tested for periods of up to one week.
- At Ameren's Meramec Plant, one-half of one unit's ESP was tested for periods up to 30 days.
- At Sunflower Electric's Holcomb Station, the entire unit's dry SO_2 scrubber-fabric filter system was tested for periods of up to 30 days.

All of the tests completed to date have demonstrated that designing sorbent injection systems to treat only a small portion of the flue gas is very challenging. Designing sorbent injection systems to treat the entire flue gas volume will require much more development (e.g.,

[7] See the DOE-NETL website for additional information concerning most of the tests contained in the Petitioners' Table: http://www.netl.doe.gov/technologies/coalpower/ewr/mercury/control-tech/control_fieldtest.html.

computational fluid dynamic modeling) and significantly more elaborate injection equipment than has been used and tested to date, making success even more challenging. Once full development and design is achieved, retrofitting full-scale systems on existing plants will be even more daunting given site-specific constraints of space and existing flue gas duct design.

B. Mercury-specific control technologies are not compatible with the Wisconsin fleet and they are not likely to achieve 90% reductions.

1. <u>The tests have not been conducted on plants that have equipment similar to that used by the Wisconsin fleet.</u>

The use of generalized information about the availability and performance of mercury-specific control technology can lead to erroneous conclusions. Instead, it is necessary to conduct realistic design studies. The tests that have been conducted to date are of limited application to the Wisconsin coal-fired utility boiler fleet because:

- 90% of the coal burned to generate electricity in Wisconsin is sub-bituminous, but most of the referenced testing has been done at plants that burn lignite and bituminous coal. Only 12 of the 41 tests listed in Petitioners' Table (Petition, Table at pp. 7-8) were done at plants that burned 100% sub-bituminous coal.
- Mercury is more easily captured with non-mercury-specific control technologies (e.g., SO_2 wet scrubbers) when emitted by bituminous coal-fired boilers than by the sub-bituminous coal-fired boilers used in Wisconsin.
- Only five units in Wisconsin are currently equipped with a baghouse, representing ~20% of the installed coal-fired generating capacity. Sorbent injection into a baghouse is far more effective in capturing high percentages of mercury emissions than sorbent injection into an ESP. However, sorbent injection will render the fly ash captured by the baghouse unfit for beneficial use.
- Approximately 15% of the installed coal-fired generating capacity in Wisconsin is equipped with hot-side ESPs. Sorbent injection into hot-side ESPs, under the best of conditions, captures less than 65% of the mercury.
- Approximately 69% of the capacity is equipped with cold-side ESPs. Sorbent injection into cold-side ESPs often captures less than 90% of the mercury.
- In both cases involving ESPs, sorbent injection renders the fly ash unfit for beneficial use.
- No existing power plant in Wisconsin is equipped with a dry scrubber-fabric filter emission control system, which was in place at the Holcomb Station listed in Petitioners' Table. As such, the Holcomb test results are meaningless as a guide to what might be achievable for mercury removal efficiency at existing power plants in Wisconsin.

Petitioners' conclusion that installation of sorbent injection systems on Wisconsin plants can achieve 90% mercury emission reductions is erroneous. A realistic design study that includes consideration of the above factors instead concludes that installation of sorbent injection at every coal-fired unit in Wisconsin will not come close to achieving 90% control without the installation of additional fabric filters. There continue to be significant uncertainties about the performance of this technology as applied to units burning sub-bituminous coal and about balance of plant impacts. Also, since there is further control research underway to enhance the mercury capture performance of SO_2 and NO_x control technologies (i.e., the type of equipment that will be installed to comply with CAIR), large-scale investment in fabric filters across the Wisconsin electricity generating system at this time may also be a significant and unnecessary capital expense.

2. Sorbent injection is an evolving technology. Advanced designs for the sorbent injection concept are being developed (e.g., TOXECON) but performance of the technology is still being demonstrated and long-term balance of plant impacts of sorbent injection are still unknown.

Petitioners place great weight on the use of activated carbon injection to capture mercury at Wisconsin's coal-fired power plants. However, as noted, sorbent injection will ruin the existing Wisconsin program for beneficial use of fly ash, lead to greater use of landfills for fly ash disposal, and forego the significant CO_2 offsets that result from using fly ash in concrete. The possible TOXECON solution to the fly ash contamination problem is still under development.

In 2001, the first "full-scale" test of sorbent injection to control power plant mercury emissions at a sub-bituminous coal-fired plant was conducted at We Energies Pleasant Prairie Power Plant[8]. This was a collaboration involving DOE, EPA, EPRI and ADA Environmental Services. A key objective in this demonstration was to determine whether sorbent technology could reduce mercury emissions and allow beneficial fly ash use. Results of several week-long tests using different levels of activated carbon injection showed that, depending on the amount of sorbent injected, between 40 and 70 percent of mercury was removed. However, injection of even small amounts of activated carbon contaminated the fly ash and prevented it from being beneficially used in concrete.

Since that first demonstration, test data for capture rates for sorbent injection at plants that burn sub-bituminous coal vary significantly. Capture rates are dependent on the type of carbon used as the sorbent material and on the size of installed ESP, among other factors.

Also on the negative side is the potential risk sorbent injection poses to power plant equipment and operations. In the electric utility industry concern for reliability is paramount. It is critical to have a better understanding of possible longer term impacts under real operating conditions that power plants experience every day, e.g., daily increasing and decreasing boiler load and electrical output levels. These risks must be identified and resolved through longer term testing in order to have confidence that retrofit technologies will not impact the utilities' ability to reliably supply electricity to consumers.

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[8] National Energy Technology Laboratory, United States Dept. of Energy, *Field Test Program to Develop Comprehensive Design, Operating, and Cost Data for Mercury Control Systems* (May 2003).

3. The emerging technology called TOXECON is still in the testing stage.

Another emerging mercury-specific control technology mentioned by the Petitioners is TOXECON, an EPRI-patented concept that is designed to capture 90% or more of the mercury present in flue gas while preserving fly ash for beneficial use.

EPRI's TOXECON concept is to place a fabric filter downstream of an existing ESP (either hot-side or cold-side) and to then inject sorbent upstream of the fabric filter to capture mercury. The fly ash captured by the existing ESP is not contaminated by the sorbent and can be beneficially used. The TOXECON captures small amounts of fly ash as well as the sorbent used to capture mercury. This "spent sorbent" is then placed in a landfill or otherwise appropriately managed.

The first demonstration of this technology is underway at We Energies Presque Isle Power Plant, located in Marquette, MI. The TOXECON has been installed downstream of three existing 80 MW, hot-side ESP-equipped units. These units burn sub-bituminous coal. The TOXECON Project at Presque Isle is a unique, joint venture between the DOE-NETL and We Energies. It was one of eight projects funded nationally under the Clean Coal Power Initiative (CCPI). The budget for the project is $53 million, of which capital equipment purchase and installation amounted to $34 million. Construction commenced in late 2003 and was completed in late November 2005.

The sorbent injection test program commenced in early 2006. However, due to unexpected problems in baghouse operation and fly ash/sorbent byproduct management, continuous full scale sorbent injection and the assessment of its mercury capture ability has been fragmented. Performance levels at or above the 90% control level have also been inconsistent. The performance of the equipment at the 90% or above control level has been limited to a maximum run of just 28 continuous days over the 16+ months of testing.

It seems likely that the concept will be capable of achieving 90% control of mercury emissions, but the testing is far from complete at Presque Isle. The demonstration has yet to show that the technology could be relied upon to meet a regulatory standard requiring consistent and reliable emission reductions of 90%. Retrofitting existing plants with this technology will also be very costly.

C. Costs of controls are significant.

The Center for Energy and Economic Development (CEED) recently completed an evaluation of the costs of complying with the mercury rule proposed by DNR[9]. The CEED cost evaluation compares the cost of Wisconsin implementing CAIR and CAMR in a manner consistent with the provisions included in the federal rule (CAIR/CAMR), to the cost of implementing CAIR and the more stringent requirements in the DNR-proposed rule (CAIR/WI Rule). The mercury rule requested by the Petitioners is more stringent than the DNR-proposed rule. Specifically, the rule

[9] Evaluation of the Compliance Implications to the Wisconsin Electric Generators of Meeting the Wisconsin Proposed Mercury Rule, James Marchetti, J. Edward Cichanowicz, Michael Hein, June 2007.

requested by the Petitioners proposes that a 90% control requirement apply beginning in 2012 compared to 2020 in the DNR-proposed rule.

According to the CEED study, the cumulative annualized compliance costs to Wisconsin utilities between 2009 and 2020 to meet CAIR/CAMR are projected to be almost $4.3 billion[10], of which $319 million are attributable to CAMR (i.e,. Hg or mercury reductions). Under a CAIR/WI Rule regulatory regime, compliance costs are projected to be almost $4.8 billion for the same 2009 to 2020 time period. Consequently, the DNR-proposed rule would increase the cost of operating coal-fired generating facilities in Wisconsin by $450 million between 2010 and 2020. ***Thus, the cost of the DNR-proposed rule is more than twice the cost of CAMR.*** Table 2 presents a summary of the cumulative annualized compliance costs to Wisconsin utilities to meet CAIR/CAMR and CAIR/WI Rule from 2009 through 2020 from the CEED study.

TABLE 2
COMPARISON OF CUMULATIVE ANNUALIZED COMPLIANCE COSTS: 2009-2020 (in billion of 2006 $)

Rules	SO_2	NOx	Hg	Total
CAIR/CAMR	3.017	0.998	0.319	4.334
CAIR/WI Rule	3.017	0.998	0.769	4.784
Differential Cost	0	0	0.450	0.450

Note that these costs include potential allowance sales for those utilities that produce excess or banked allowances. These sales were netted out of the total annualized compliance costs for each case under CAIR/CAMR. This potential asset would be lost under the DNR-proposed rule, because the DNR-proposed rule does not allow for banking and trading. Wisconsin utilities would have an accumulated value of $156 million in mercury allowances under CAMR during the 2010 – 2020 time period. The restrictions on banking and trading represent not only a lost economic asset, but also a lost environmental benefit.

The costs of meeting the rule requested by Petitioners would be significantly higher than the DNR-proposed rule since Petitioners would accelerate the compliance date by eight years. As discussed earlier in this Response, there are serious technological uncertainties and risks associated with Petitioners' timeline. While the CEED study does not specifically address the cost of meeting the requirements requested in the Petition, it is a useful benchmark for evaluating the costs of any state rule that is more stringent than the federal CAMR.

The full CEED study is being submitted separately to DNR as public comment on the DNR-proposed rule.

[10] Annualized compliance costs included an annual capital charge for control technology, annual fixed and variable O&M costs for control technology, changes in annual fuel costs due to compliance and allowance costs.

VI. WILL THE RULES PETITIONERS REQUEST ACHIEVE THE GOAL OF THE PETITION?

The fundamental objective of the Petitioners' request for these rules is to **minimize mercury deposition to Wisconsin lakes and rivers.** The relevant question is -- will the requested rules accomplish this objective?

Based on agency and peer-reviewed science, the answer is "no" -- the rules Petitioners request will not achieve the stated goal of minimizing mercury deposition to Wisconsin lakes and rivers[11].

This is important for DNR and the Board to consider. The cost of implementing new emission reduction requirements for Wisconsin's electric generation system will be borne by the ratepayers – the citizens of Wisconsin. In turn, the value of these electricity rate increases should be measured by the environmental results that they achieve.

The science of mercury deposition combined with advanced modeling of utility mercury emissions provides a quantitative estimate of the potential environmental impacts of reducing Wisconsin utility emissions beyond those levels required by CAMR. Petitioners consider information about the impact of more stringent Wisconsin regulations on reducing fish consumption advisories to be irrelevant. We disagree. Indeed, this understanding is critical to the NRB's consideration of the Petitioners' request.

A review of the nature of mercury in the environment begins to define the difficulty and complexity of solving global environmental concerns with state-only regulations. U.S. mercury emissions make up about 6% of the world total[12]. A subset of these U.S. mercury emissions comes from U.S. utility emissions. U.S. utility mercury emissions make up less than 2% of the world total[13].

In addition, mercury is not necessarily deposited close to where it is emitted. When emitted from plants with tall stacks, the distance mercury travels is related to the form emitted. There are two primary forms of mercury emitted from power plants: elemental mercury and oxidized mercury. Elemental mercury tends to enter the global mercury cycle and may be retained in the atmosphere for up to one year before being deposited, creating the possibility that it will travel around the earth several times before deposition. In other words, elemental mercury that deposits in Wisconsin probably did not originate in Wisconsin.

Oxidized mercury, on the other hand, is more likely to deposit relatively quickly, suggesting the possibility of local or regional deposition. Even so, only about 20% of the total oxidized mercury emitted is likely to be deposited within 30 kilometers of its origin; the rest is subject to

[11] Petitioners also reference new information on health impacts in support of their requested rule. This Response does not address the issue of health impacts. However, it is important to note there are significant concerns about the methodology used by the Wisconsin Department of Health and Family Services' study and the validity of its results.
[12] Electric Power Research Institute, *Integrated Approaches to Managing Mercury*, at 1 (Sept. 2006).
[13] *Id.* at 1.

conversion processes in the atmosphere where oxidized mercury is either rapidly or slowly converted into elemental mercury. It would then, like elemental mercury, be likely to travel long distances before being deposited[14].

What does this mean for mercury emissions and deposition in Wisconsin? This question can be answered numerically, using generalized deposition estimates, or it can be assessed using a more rigorous mercury modeling simulation.

On a strict numeric estimate basis, between 10 and 30% of the mercury emitted from Wisconsin's power plants is oxidized mercury; of this amount, at most 20% is likely to be deposited within 30 kilometers of the source. Therefore, at most, only about 6% of the mercury emitted from power plants in Wisconsin will be deposited nearby. Even after a 70% reduction, as required by CAMR, the remaining mercury emitted would be elemental mercury, which does not deposit near its source. Therefore, requiring a 90% mercury reduction instead of CAMR's required 70% reduction would not accomplish any incremental reduction in mercury deposition in Wisconsin.

These numeric estimates are in fact consistent with mercury deposition modeling conducted by EPA, the Lake Michigan Air Directors Consortium (LADCO), and EPRI. EPA conducted a mercury modeling study in the mid-1990s as part of its comprehensive Mercury Study Report to Congress[15]. This study estimated that less than seven percent of mercury emissions from large coal-fired units is deposited within 50 km of the facility. As part of the development of CAMR, EPA conducted additional utility mercury modeling[16]. This modeling showed that all coal-fired power plants in the U.S. contributed less than 10% to mercury deposition occurring in Wisconsin.

In January 2002, LADCO released the results of its Midwest mercury study. It estimated that utility sources in Wisconsin contribute one to five percent of the simulated wet deposition as measured at the four Wisconsin Mercury Deposition Network (MDN) monitors[17].

In May 2002, a study developed in cooperation with EPRI and conducted by Atmospheric and Environmental Research, Inc. (AER) was released[18]. This study found that mercury deposition declines by one to four percent over most of the state when Wisconsin utility emissions are completely eliminated. The model findings were also verified against actual measurements of mercury deposition collected from the Wisconsin MDN. These finds have recently been confirmed by AER and corroborated with the requests of other agency and independent research. See AER's submittal as part of the comment period related to the current DNR rule proposal.

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[14] *Id.* at 2.
[15] United States E.P.A., *Mercury Study Report to Congress, Volume III: Fate and Transport of Mercury in the Environment* (EPA-452/R-97-005, 1997)
[16] United States E.P.A., *Regulatory Impact Analysis of the Clean Air Mercury Report*, (ch. 8 EPA-452/R-05-03 2005).
[17] ICF Consulting, Application of the REMSAD Modeling System to the Midwest, Memorandum to LADCO, San Rafael, California (2002).
[18] K. Vijayaraghavan, K. Lohman, P. Karamchandani and C. Seigneur, *Modeling Deposition of Atmospheric Mercury in Wisconsin*, Report CP136-02-1 to the Electric Power Research Institute (EPRI), Palo Alto, CA (2002).

Each of these simulated utility contributions is likely to be conservative because the modeling techniques used at that time simplified the chemical reactions that take place in power plant emissions[19]. Using simplified chemical reactions has the impact of overestimating the proportion of oxidized mercury and therefore overestimating localized mercury deposition. The findings in the report therefore represent likely upper limits on regional deposition from Wisconsin coal plants. More recent modeling of utility emissions has improved, including the ability to more accurately represent mercury speciation and thereby refine deposition estimates.

These agency and peer-reviewed modeling simulations are important to consider when evaluating the Petitioners' request for rules.

While it may initially seem a simple equation -- reduce mercury emissions from Wisconsin utilities and reduce deposition in Wisconsin lakes and rivers – the science is to the contrary. It is incumbent on the Board to consider this more complicated reality in determining the most appropriate response to the Petitioners' request.

VII. NEIGHBORING STATES

Petitioners point to neighboring states as support for their position that Wisconsin should also adopt a 90% reduction rule. More specifically, Petitioners reference Illinois, Minnesota, and Michigan[20], and assert that all three states have enacted 90% reduction requirements. Petitioners characterize these programs as generally requiring coal-fired units to achieve a 90% reduction in mercury emissions by 2009 at the earliest and 2015 at the latest. These characterizations do not accurately reflect the facts.

Petitioners gloss over certain important aspects of those programs—like the significantly lower reliance on coal-fired generation (approximately 49% compared to 75% in Wisconsin) in Illinois—that played a significant role in passage of the requirements. In Minnesota, the 90% reduction requirement only applies to three facilities (six units in total), operated by just two utilities, and most of these units are already fitted with control equipment – making the 90% reduction much less costly to implement. And, Michigan's proposed rule is not yet final but is to include state-wide trading of allowances and both technological- and cost-based exceptions. A summary of the relevant provisions, by state, is set forth below.

A. Illinois:

Illinois recently finalized mercury control regulations[21]. The Illinois mercury regulations apply to coal-fired generating units of greater than 25 MW capacity. The Illinois regulations establish a performance standard of 0.008lb/GWh gross electric output, or a minimum 90% reduction of

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[19] C. Seigneur, K. Lohman, K. Vijayaraghavan, J. Jansen and L. Levin, *Modeling atmospheric mercury deposition in the vicinity of power plants*, J. Air Waste Mgt. Ass'n., 56: 743-751 (2006).
[20] Michigan has not yet adopted final mercury regulations.
[21] See Illinois Pollution Control Board Proposed New 35 Ill. Admin. Code 225, Control of Emissions From Large Combustion Sources, Opinion and Order, available at http://www.ipcb.state.il.us/documents/dsweb/Get/Document-55427/.

output mercury, applicable beginning January 1, 2009, with various exceptions that extend the compliance deadline to 2015.

Importantly, less than one-half (approximately 49%) of Illinois electricity is produced by coal-fired power plants[22]. This is significantly less than the 75% coal-fired generation in Wisconsin, and has implications for the overall cost of beyond-CAMR mercury regulations to Illinois ratepayers. The lower proportion of affected generation is also a factor in the timeline for compliance with the rule.

The Illinois rule reflects multi-emission compliance alternatives that were developed through individual negotiations with the state's largest utilities. These alternatives are specifically based on the characteristics of their utility systems, and include compliance extensions intended to allow additional time for control installation on smaller units and to stage installation of emission controls for NOx and SO_2. The agreements are based on the commitment to achieve deeper levels of NOx and SO_2 control in exchange for not meeting the performance standard for mercury.

The rule includes other alternatives, including emission averaging across separate emissions units owned by the utility, to achieve the standard subject to some minimum control limits. There is also a "temporary technology control option". This option recognizes the uncertainty of mercury control technology performance and allows a certain percentage (25%) of generating units to achieve a lesser standard of control than the performance standard, so long as they 1) utilize a sorbent injection system; and 2) utilize either a hot-side ESP or fabric filter on the unit.

B. Minnesota:

Minnesota recently enacted the Mercury Emissions Reduction Act of 2006 (the Act)[23]. The Act is the next step in a comprehensive plan that the state has been following since the 1990s to reduce emissions of mercury from all Minnesota sources. In 2005, Minnesota met a 70% reduction target from 1990 levels of emissions from all Minnesota sources. It was only after this comprehensive effort that Minnesota proceeded to legislation aimed at additional reductions from the state's largest remaining air sources of mercury (coal units).

The Act only applies to "qualifying facilities". Qualifying facilities are those that have a total net capacity of greater than 500 MW from all coal-fired electric generating units at the facility. Therefore, the Act only applies to six "targeted" units (owned by two utilities) out of a total of 27 coal-fired units in Minnesota. At this time the Minnesota Pollution Control Agency (MPCA) has not yet announced its intentions for developing a state plan to implement the CAMR requirements, which would apply to qualifying facilities as well as the remaining 21 coal-fired units.

The Act allows for supplemental units to provide emission reductions as offsets to the requirements at the qualifying facilities. Of the two affected utilities, one utility is able to apply

[22] About 50% of Illinois' electricity is generated by nuclear power plants. Source: U.S. Energy Information Administration, http://tonto.eia.doe.gov/state/.
[23] Minn. Stat. § 216B.68 et seq.

reductions potentially achieved utilizing an innovative control technology employed at a supplemental unit to offset approximately 20% of the reduction requirement at its qualifying facility. This translates to a net emission reduction requirement of approximately 70% across that utility's total system.

The Act requires the public utilities owning these qualifying facilities to develop and submit a mercury emissions reduction plan for each targeted unit. The plan must propose to employ the available control technology for mercury removal that is designed to remove at least 90% of the mercury emitted from the unit. The Act also requires the utilities to submit alternative plans that are designed to come as near as technically possible to achieving the 90% reduction target without imposing excessive costs on the utility's customers.

The emission reduction requirement in the Act is also a function of the emission controls already installed at the qualifying facilities for purposes of reducing SO_2. The mercury reduction capacity of these controls is then reflected in the applicable compliance requirements. Plants with dry scrubbers already installed must implement the mercury emission reduction plan that is most likely to result in removal of at least 90% of the mercury emitted from the unit by December 31, 2010. Plants with wet scrubbers must implement their plan by December 31, 2014. The earlier compliance date for units with dry scrubbers recognizes that more mercury research has been completed to date associated with this type of plant configuration. The extended compliance date for units with wet scrubbers recognizes the need for additional technology development in order to achieve this same level of mercury control technology research.

The MPCA and the Minnesota Public Utilities Commission (MPUC) must review and evaluate the emission reduction plans, considering the environmental and public health benefits, the assessment of technical feasibility, competitiveness of customer rates and cost-effectiveness of the utility's proposal. The MPUC must order the implementation of the mercury emission reduction plans unless it determines the plan fails to provide for increased environmental and public health benefits or would impose excessive costs on the utility's customers. No plans for approval have been submitted yet by the affected utilities.

Finally, the Act also establishes how the additional mercury control costs will be passed on to consumers through electricity rate increases. Mechanisms for immediate recovery of all implementation costs (including recovery for costs associated with construction work in progress), as well as an authorization for performance-based ratemaking to reward facilities for reducing emissions beyond 90%, are included in the Act. According to legislative analyses of the Act, the ratemaking authorization was a critical aspect of its' passage.

C. Michigan:

Michigan has proposed but has not yet finalized mercury control regulations[24]. The proposed Michigan rules apply to all coal-fired electric generating units with greater than 25 MW capacity. The proposed rules include an allowance for in-state trading among affected sources.

[24] The rules are being developed as Mich. Admin. Code §§ 336.2501-336.2516.

The proposed Michigan rules establish a declining cap on mercury emissions, consistent with the statewide emission cap issued for Michigan by EPA in CAMR. The initial cap enters into force on January 1, 2010, with the secondary cap entering into force on January 1, 2015. In addition to the secondary cap, beginning in 2015 all units will be required to comply with either a 90% reduction in mercury emissions on a calendar year basis, or an emissions rate of 0.008 lb Hg/ GWh. Importantly, the Governor's Directive for developing these rules[25] includes two key provisions:

1. Technical Exception: "First, a utility would be given additional time to comply if it installs and operates mercury reduction technology, but upon testing is unable to demonstrate compliance with the required reduction or emission limit."

2. Cost-based Exception: "Second, additional compliance time would be provided if a power plant demonstrates that the annualized incremental cost of mercury reduction technology to go beyond CAMR will exceed a specified percentage of the gross revenue from electric generation for the utility system."

Neither of these exceptions has been developed yet.

What this summary demonstrates is that our neighboring states recognize that "one size does not fit all" when designing realistic approaches to mercury emission reduction. Each of these states takes into account the nature of its electricity generating fleet, fuel type, existing emission controls, and the timing and costs of further reductions.

VIII. NR 446 AND CAMR

In support of their requested rules, Petitioners assert that ch. NR 446 contemplates rule adjustments and that the federal CAMR rule was developed illegally (Petition at pp. 10 and 11-14). Because Petitioners have raised these points, we address them briefly here.

Petitioners address NR 446.12 which imposes an obligation on DNR to periodically evaluate and make recommendations for revisions to NR 446. While DNR and the NRB may review rules for various reasons, that authority does not mandate the substantive revisions Petitioners are seeking. Rather, the NR 446.12 provisions impose the obligation to evaluate the status of mercury emission control development and whether the emission limits in the rule are achievable. The Department may also make recommendations for rule changes, but must also assess the impact of these recommendations on mercury concentrations in state waterbodies. Thus, there is an obligation for rule accountability in terms of the environmental impact of recommended rule revisions.

[25] Michigan Governor's Directive, 4/17/06.

More importantly, however, the rules Petitioners request would be more stringent than the applicable federal rules and state law[26], and DNR's regulations prohibit their adoption. NR 446.029 states:

> If a federal emission standard limiting mercury emissions from a major utility is promulgated . . . the department shall adopt a similar standard, including administrative requirements that are consistent with the federal administrative requirements. The standard adopted by the department may not be more restrictive in terms of emission limitations than the federal standard. The administrative requirements of the standard . . . shall be the same as the federal standard.

DNR has an affirmative obligation to conform its regulations to the federal regulations within 18 months of promulgation of these federal regulations. NR 446.029 states:

> No later than 18 months after the promulgation of a federal emission standard limiting mercury emissions from a major utility, the department shall revise this subchapter. . . to comply with the provisions of this section and s. NR 446.06(4).

CAMR was issued March 15, 2005. The Wisconsin utilities have an obligation to comply with CAMR. Importantly for this discussion, the utilities need to know how CAMR will be applied in Wisconsin so they can plan accordingly. At the NRB's direction, DNR held public hearings and solicited public comment during November and December 2005 on state rule options to implement CAMR. DNR has an affirmative obligation to adopt a state rule to implement CAMR and has not yet done so.

Apparently to counter this requirement, Petitioners cite various sources to support their contention that the "process" EPA used to develop CAMR was flawed and thus cannot be relied upon by DNR. While a thorough analysis of CAMR's legality is outside the scope of this Response, there are a few key points to consider. CAMR is a federal rule which Wisconsin is bound to follow and implement pursuant to both the Clean Air Act and Wisconsin's own statutes and regulations. If Petitioners believe CAMR is illegal, the venue for that challenge is the federal court, not the NRB. The NRB does not have the authority to invalidate a federal rule and must assume all federal rules are legal unless overturned or stayed by a federal court[27].

IX. <u>CONCLUSION</u>

The Wisconsin utilities are obligated to install SO_2 and NO_x controls by 2010 to comply with the federal CAIR (and CAMR Phase I) requirements. The level of mercury reductions (co-benefits)

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[26] Wis. Stat. §§ 285.11(9) and 285.27 also prohibit DNR from adopting a more stringent emission limitation than EPA's without the statutorily required analysis that would justify these more stringent emission standards as required by Wis. Stat. §§ 285.11(9), and 285.27(2)(b).

[27] The federal court, which is currently reviewing this issue, has refused to stay the rule's effectiveness. *New Jersey v. United States EPA*, No. 05-1097 (D.C. Cir. Aug. 4, 2005 Order).

that will be achieved in Wisconsin is uncertain. As a result, the type of mercury-specific control technologies that may be required to meet CAMR Phase II is uncertain. Mercury-specific control technology that will work on the Wisconsin fleet is not yet commercially available. The anticipated capital and O&M costs associated with installing mercury-specific controls by 2012 are significant.

Under all of these circumstances, the best approach in 2007 is for the Wisconsin utilities to implement CAIR/CAMR Phase I by 2010, optimize the mercury emission reductions that are achievable with that SO_2 and NO_x reduction control technology, and then tailor the additional mercury-specific controls needed to achieve the 2018 CAMR Phase II reduction requirement. We urge the Board to reject an approach that would require the Wisconsin utilities to achieve a 90% reduction in mercury emissions by 2012.